

**An Advanced Fracture Characterization and Well Path Navigation System for
Effective Re-Development and Enhancement of Ultimate Recovery from the
Complex Monterey Reservoir of South Ellwood Field, Offshore California**

Quarterly Technical Progress Report

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Progress Report May 1 - September 30, 2000

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Abstract

Venoco Inc, intends to re-develop the Monterey Formation, a Class III basin reservoir, at South Ellwood Field, Offshore Santa Barbara, California.

Well productivity in this field varies significantly. Cumulative Monterey production for individual wells has ranged from 260 STB to 8,700,000 STB. Productivity is primarily affected by how well the well path connects with the local fracture system and the degree of aquifer support. Cumulative oil recovery to date is a small percentage of the original oil in place. To embark upon successful re-development and to optimize reservoir management, Venoco intends to investigate, map and characterize field fracture patterns and the reservoir conduit system. State of the art borehole imaging technologies including FMI, dipole sonic and cross-well seismic, interference tests and production logs will be employed to characterize fractures and micro faults. These data along with the existing database will be used for construction of a novel geologic model of the fracture network. Development of an innovative fracture network reservoir simulator is proposed to monitor and manage the aquifer's role in pressure maintenance and water production. The new fracture simulation model will be used for both planning optimal paths for new wells and improving ultimate recovery.

In the second phase of this project, the model will be used for the design of a pilot program for downhole water re-injection into the aquifer simultaneously with oil production. Downhole water separation units attached to electric submersible pumps will be used to minimize surface fluid handling thereby improving recoveries per well and field economics while maintaining aquifer support.

In cooperation with the DOE, results of the field studies as well as the new models developed and the fracture database will be shared with other operators. Numerous fields producing from the Monterey and analogous fractured reservoirs both onshore and offshore will benefit from the methodologies developed in this project.

This report presents a summary of all technical work conducted during the first quarter of Budget Period I. The primary task carried out in this period was the preparation of a data-set containing regional fracture information for the Monterey formation in the Santa Barbara Channel.

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Introduction

The Field Demonstration site for this Class III (basin clastic) Program Proposal is the South Ellwood Field located offshore California. The Monterey Formation is the main producing unit in the South Ellwood Field and consists of fractured chert, porcelanite, dolomite, and siliceous limestone interbedded with organic mudstone. This reservoir has an average thickness of 1,000 feet, and lies at subsea depths of approximately -3,500' to -5,000'.

Venoco and USC jointly submitted an application to conduct a DOE co-operative investigation of the Monterey formation at South Ellwood in June 2000. The DOE granted this application in July 2000.

Executive Summary

Venoco and USC prepared a proposal for a DOE sponsored joint investigation of the fractured Monterey formation. It was agreed that Venoco would construct the geologic model for the field and gather new reservoir data as appropriate. USC would then develop a simulation model that would be used to optimize future hydrocarbon recovery. Joint Venoco-USC teams were established to manage the flow of data and insure that Venoco and USC activities remained synchronized. A co-operative agreement was signed with the DOE on July 31, 2000.

Activities began in May 2000 with a pre-authorized study of regional fracture data. The naturally fractured Monterey has proved very difficult to model with conventional reservoir simulation algorithms based on the Warren and Root model. A new model was proposed where the fracture system simulated by a pipeline network. The mathematical formulation of this model was completed and is presented fully in the discussion under Task III.

In preparation for the creation of this simulation model, all relevant geological and reservoir data for South Ellwood field were collated from a variety of sources both paper and digital. An electronic database constructed to warehouse this data and make it freely available. Population of this data was underway at the end of this report period. The database will be publicly available in the form of a CD-ROM.

1980's vintage 3-D Seismic data was processed by Venoco and re-interpreted using SMT. A set of normal faults running north-south were identified for the first time and recognized as the primary control on fracture development. A 3-D geological model was constructed in EarthVision using this latest interpretation. The new geological model was presented at the Western Regional meeting of the AAPG in June 2000.

Task 0.1 Consolidation of Regional Fracture Data

A literature survey was conducted to review published studies on the tectonic and diagenetic control on the formation of fractures in the Monterey Formation. The Monterey formation is unusual in that it forms both the source and reservoir rock for major petroleum reserves in southern California. The porosity and permeability in these reservoirs are almost entirely due to fractures and faults that occur on a wide range of scales from submillimeter in brecciated chert beds to kilometers in major faults. Strategies for the optimal development of Monterey reservoirs depend on knowledge of the geometry of these fracture networks.

Observed fracture patterns reflect both the lithology and tectonic history of the Monterey formation. The intensity of fracturing is largely controlled by the lithology while the orientation reflects the tectonic history.

Tectonic History

About 30 my B.P. the East Pacific Rise collided with the trench at the North American – Pacific plate boundary in southern California changing the relative motion from convergence and subduction to strike-slip displacement along the newly formed San Andreas fault system. This change in tectonic style initiated the formation of several basins that became “depocenters” for both continental terrigenous and marine organic sediments. Rapid basin subsidence and marine transgression began about 22.5 my B.P. and was so rapid that it outpaced sediment accumulation. Continental sediments were trapped in near shore estuaries and deltas and the basins became starved of terrigenous sediments. About 15 to 13 my B.P. a major climatic reorganization from preglacial to glacial conditions caused oceanic upwelling and associated diatomic plankton blooms leading to an increased biogenic silica influx to the sediment starved basins. Anoxic conditions at depths between 500 and 900 m preserved the organic rich sediments by eliminating microorganisms at these depths. The Monterey formation, deposited between about 17.5 and 6 my B.P., reflects this unusual combination of circumstances. It was deposited as a diatomaceous and coccolithic, foramiferal ooze devoid of terrigenous sediment. The resultant sedimentary rock is diatomaceous, phosphatic, dolomitic, and rich in organic matter. The composition can be extremely variable from location to location.

The history of basin formation and subsequent deformation is complex and controversial. It is complicated by paleomagnetic evidence that the entire region experienced a 90° clockwise rotation between about 16 and 6my B.P., presumably associated with the right-lateral strike-slip motion at the plate boundary.

From 6my B.P. till the present, the Ventura basin has been subject to NE-SW compression associated with the “big bend” in the San Andreas Fault. This has resulted in a deepening of the basin and extensive folding. Under the northern Santa Barbara Channel, folding is geometrically simple with fold axes running approximately E-W. Warping of the Monterey was gentle between 6 and 2my B.P. Rapid deformation began about 2 my B.P. and continues at a reduced rate today. Virtually all the faults and open fractures in the Monterey formation are associated with this folding.

Fracture Patterns in the Monterey

The intensity of fracturing in the Monterey depends primarily on composition and degree of diagenesis of the rock. Silica rich beds are altered from opal-A to opal-CT to quartz (chert) becoming increasingly brittle with each transformation. The calcareous rocks are similarly embrittled by the alteration to dolomite.

The orientation of fractures is determined by the tectonic deformation. Fractures are associated either with faulting or folding. Large scale faults tends to divide the reservoirs into compartments, but they play a minor role in the storage and transport of hydrocarbons. The vast majority of fractures are associated with the folding. Since most of the folding occurred between 2 and 0.5 my B.P, it reflects the current NE-SW compression.

Large scale folding in the Monterey is slightly asymmetric and has associated large scale thrust faulting. This structure is apparent in seismic section where the thrust faults are identifiable because they offset lithologic horizons. Less apparent in seismic section are the numerous breccia zones that play the major role in hydrocarbon storage and transport. Brecciated zone can appear as either dikes, which cut bedding planes at a high angle, or sills which follow the bedding planes. These latter are also called “stratigraphic breccia” because they tend to be confined to individual brittle strata. Breccia dikes tend to be oriented either subparallel to the fold axis or within 30° of being orthogonal.

The stratigraphic breccia sills are formed by folding brittle strata. Folding is accommodated by slip between brittle and more ductile beds. More ductile layers tend to flow while the more brittle layers, especially the chert, tend to fracture. The brittle layers sometimes contain microscopic highly fractured “drag folds” caused by the slip at their boundaries with more ductile beds. The cores of some large scale folds are very tight and also contain highly brecciated brittle layers. Some folds tighten with depth while others become more gentle. It is difficult to differentiate these two cases using seismic data that does not penetrate the core of most folds.

Task I- Database

The study of the Monterey Formation at South Ellwood requires easy accessibility of both raw and interpreted data. Major components of the existing data-set are: raw and interpreted wireline log data, core data, mud log data, production data, well test data, special core analysis and fracture studies, PVT data, geological and geophysical data. Many of the interpretations have been prepared with specialty software. Change of ownership from ARCO to Mobil and now recently to Venoco has resulted in accumulation of various archives of data and in different formats.

Task I of Budget Period I includes designing a database, digitizing records, populating the database, and providing a graphical representation. The design of the database is nearly complete - see Figure 1. Table 1 gives an inventory of the data currently to be included in the database. Some of the data will be available in its raw form and the rest will be interpreted. Table 2 is a list of all the data already used to populate the database. Table 2 also indicates processing done before inclusion of the data in the database. Most of the data needed to be digitized. Some data that had been digitized, was in an obsolete format, not accessible by current software packages. These data were re-digitized into an accessible format. Adobe Acrobat was chosen since it is both platform independent and could be uploaded to an Internet site.

Table 1-Inventory of Data for the South Ellwood Field

	Raw	Interpreted	Summaries
Reservoir	PVT, DST, Well test, Water & oil & gas analysis, Pressure, Capillary Pressure Test	PVT & DST & Well Test & Pressure diagnostic, Fracture Indicator	Pressure history by well
Completion	Directional Survey, Fluid Entry	Well bore Diagram	Slots and Well Utilization
Production	Tables	Diagnostic plots	Work over Summary
Geologic	Fracture Azimuth, Core Photos, X-ray diffraction, Well Log data	Fracture Data, Lithology Descriptions, Core Analysis, Core Fracture Study, 3D geologic, Seismic, 3D Fracture Model	Core Data Summary, Formation Tops
Historical	Well History	Event Calendar	Summary of well histories
Maps		2D Structure, Cross section, Production Bubble	

DATABASE STRUCTURE

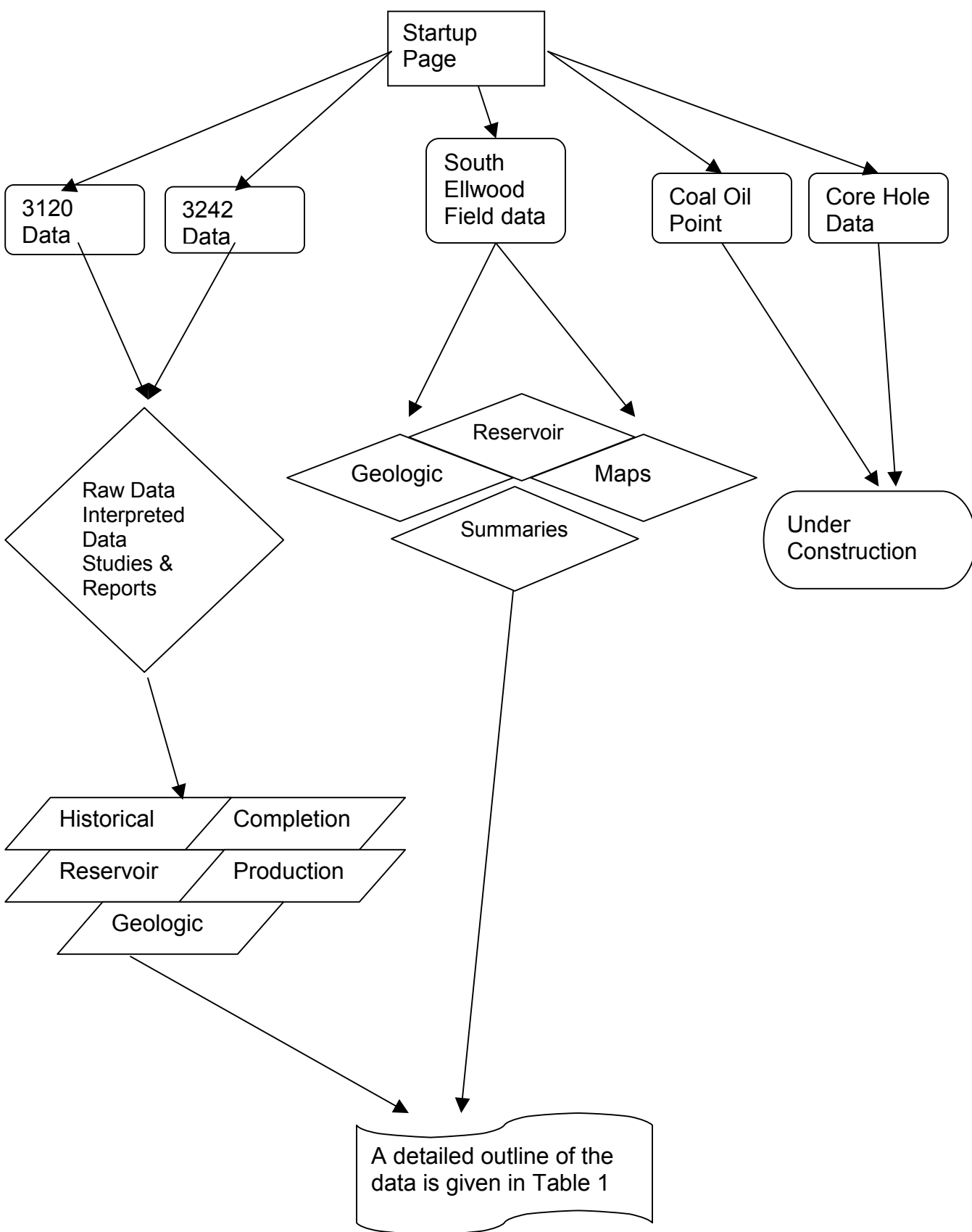


Figure 1- Design of the South Ellwood Database

Table 2-Status of Data Preparation

Data Type	Available As	Converted to:
PVT data	Hard Copy Only	Scanned into GIF & pdf format
DST data	Excel format/outdated software	Used excel & written to pdf format
Well Test	Hard Copy Only	Scanned into GIF & pdf format
Water Analysis	Hard Copy Only	Scanned into GIF & pdf format
Gas Analysis	Hard Copy Only	Scanned into GIF & pdf format
Oil Analysis	Hard Copy Only	Scanned into GIF & pdf format
BH Pressure	Hard Copy Only	Scanned into GIF & pdf format
Capillary Pressure Data	Hard Copy Only	Scanned into GIF & pdf format
Fracture Indicators	Hard copy logs & digitized data	Digitized into LAS format
Dipmeter Data	Hard copy logs & digitized data	In progress
Workover Summary	Access Database	Exported & written to pdf format
Directional Survey	Word document	Converted & written to pdf
Fluid Entry Surveys	Excel document	Converted & written to pdf
Well Bore Diagrams	Visio document	Converted & written to pdf
Production Data	Access Database	Exported & written to pdf format
Fracture Azimuth	Hard copy logs & digitized data	In progress
Core Photos	Hard Copy Only	Scanned into GIF & pdf format
X-Ray Diffraction data	Hard Copy Only	Scanned into GIF & pdf format
Fracture aperture Data	Hard Copy Only	Scanned into GIF & pdf format
Lithology Descriptions	Hard Copy Only	Scanned into GIF & pdf format
Core Analysis	Hard Copy Only	Scanned into GIF & pdf format
Well Log data	Access Database	Exported & written to pdf format
3D Geologic Model	None	In progress
Maps	Hard Copy Only	In progress
Seismic	SEGY Tapes	In progress

Task II- New Data

None during this quarter

Task III-Reservoir Studies

We proposed the development of a new fracture modeling approach to realistically simulate the history of the wells and the reservoir as a whole. We took steps to review the literature and started the formulation of the model.

Historical Perspective:

The South Ellwood Field, discovered in 1964, was originally developed in the Lower Miocene Rincon and Vaqueros Sandstones. The overlying Middle Miocene Monterey Formation later was recognized as commercially productive and quickly became the

primary reservoir The field currently delivers 4000BOPD and has produced 60MMBO and 50BCFG (1/31/2000). The field was re-interpreted in the mid 1980's utilizing 1983 vintage 2D and 3D seismic data. Integrated geologic study continued in the early 90's based on the original structural interpretation. South Ellwood has always been mapped as a faulted, slightly asymmetric, elongate EW anticline with a major bounding reverse fault along the south flank and a long north flank. The prolific Coal Oil Point seeps have generally been associated with the crest of the structure.

Venoco acquired the South Ellwood in 1997 and initiated a modern reservoir characterization study of the field. The 3D seismic was completely reprocessed and reinterpreted. A 3D geologic model was built incorporating the new seismic interpretation as well as logs, dipmeter, core and outcrop information.

Monterey stratigraphic picks have not changed significantly from previous interpretations. Improved seismic imaging has lead to important structural changes. The overall structural trap is a 2-way fault and dip trap with virtually no north limb. The north and northwest bounding faults are large down-to-the-north and west faults with normal sense displacement, similar to the Refugio Fault, which crops out to the north onshore. The north-bounding fault intersects the sea floor and is the source of the La Goleta and Holly seeps.

Geological Modeling:

A preliminary geologic model was constructed utilizing existing data (original processing of 3D, adjacent 2D, well control, and limited out crop data. This early interpretation demonstrated the utility of the EarthVision software for creating a 3D earth model of a complex structure. It also identified for the first time that apparent normal faults create part of the hydrocarbon accumulation at South Ellwood and are also directly related to the natural oil and gas seeps on the sea floor.

Characterization and Simulation Methods for Fractured Reservoirs

From a comprehensive review of literature, the existing methods for characterizing and modeling the fractured reservoirs can be summarized in the following categories:

Continuum Single Porosity Modeling. This model is simple but lacks accuracy. When simulation blocks are quite large and reservoirs have a very dense distribution of fractures, the formations can be regarded as a single porosity media.

Continuum Dual Porosity Modeling. This model is widely used in petroleum reservoir simulation. It assumes that at each node there exist intersecting fracture and matrix blocks. The fractures are flow channels and the matrix is the storage of the formation. The flow between fractures and matrix is modeled by an inter-media flow equation. The primary advantage of dual-porosity flow models is that they provide a tool to account for the delay in the oil response of the rock mass. The delay is caused by fluid that is resident in less permeability matrix blocks. However, this conceptual model needs to solve simultaneously 4 equations at each node, i.e., solve 4 unknowns (oil pressure in

the fractures, oil saturation in fractures, oil pressure in matrix and oil saturation in matrix). This requires intense computational work for the solution of the model. Other drawbacks of the model are that (a) it over-regularizes the geometry of the fracture network that may be important when simulation scale is not very large; (b) it is difficult to estimate accurately the fracture and matrix permeability and porosity.

Continuum Stochastic Modeling. This modeling method first generates conditional permeability and other properties of a reservoir. Then, stochastic flow theory provides equations to estimate the effective conductivity ellipse for anisotropic porous media. However, the model mostly deals with single-phase flow. Only recently, multiphase flow has been studied. Its application is still subject to research.

Discrete Fracture Network Modeling. During the last two decades, this model has been extensively studied. It assumes that spatial statistics associated with the a fracture network (including fracture orientation, fracture trace length, fracture density, fracture size, fracture transmissivity etc.) can be measured from borehole observation, borehole well logs, cores, surface outcrop, subsurface excavations and well tests. These statistics can be used to generate realizations of fracture networks with the same spatial properties. Other fluid flow properties can be examined from these fracture network realizations. For example, to obtain pressure distribution at all points in the network, a very large-order system of equations has to be solved assuming single phase and incompressible fluid flow in the fracture network and conservation of fluid mass at each fracture intersection. After the solution is applied to all fracture network realizations, a Monte Carlo algorithm can be used to infer the expected behavior of the fractured system and the variability about the mean. It is evident that this model needs extensive computational resources to solve the system of pressure equations. Thus, this approach cannot be used for studying a large block in a reservoir with very large number of fractures. Due to computational limitations, the method is also very difficult to apply to compressible multiphase flow. Since this model simulates the fluid flow only in fractures, it is not suitable to be used in forecasting fractured reservoirs with a permeable matrix.

Pipeline Network Model for Fractured Reservoirs

Continuum Single Porosity and Continuum Stochastic Models lead to conventional heterogeneous reservoir simulations, which may be too simplistic for a typical fractured reservoir. On the other hand, Discrete Fracture Network Models are so computationally intensive that they are impractical. Continuum Double Porosity Models are frequently used at the present time but require solving four unknowns for all nodes in the system simultaneously. On a typical large scale simulation this demands huge computer resources.

We formulated an alternative pipeline network model as originally proposed by Ershaghi and Voskanian for fractured reservoir simulation. Figure 2 shows the schematics of this model in two-dimensional case. The same procedures can be used for three-dimensional situations. The major fractures in a reservoir are simplified to a regularly connected pipeline network. The pipelines can be arbitrarily connected in 3D space according to the fracture distribution in the same space. The radius of each section of the pipeline may have different diameters, which are generated from the knowledge of

major fracture locations and their flow capacity in the reservoir. These pipelines serve as the flow channels in the reservoir. This simplification makes the pressure calculation much easier than in the Discrete Fracture Network Model. Each intersection of the pipelines is embedded in a matrix block that has storage equivalent to all micro-fractures and granular storages in that block. The interchanging flow between matrix and its embedded pipelines is assumed to occur only at the junction of pipelines. Figure 3 shows the details of the fluid interaction between pipelines and matrix storage. It is assumed that, due to capillary pressure effects, water enters the matrix storage and oil leaves the storage.

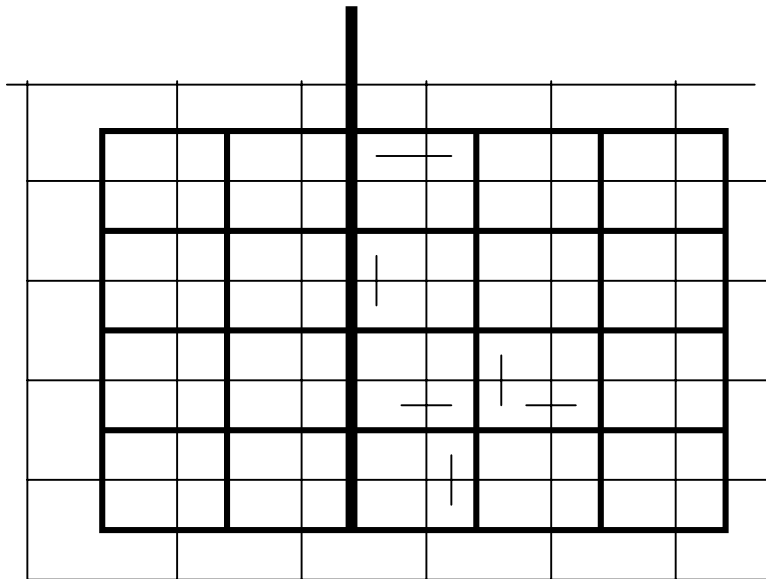


Figure 2. Schematics of pipeline network model.

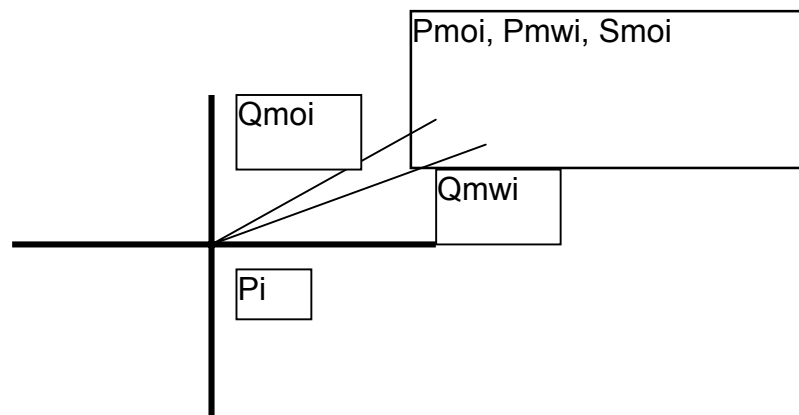


Figure 3. Schematics of interaction between fracture and matrix storage.

According to the fluid dynamics in pipelines, the transient flow for pipe connecting junction “i” and “j” can be expressed by

$$\frac{L_j}{g A_j} \frac{dQ_{ti,j}}{dt} = H_j - H_i - K_j Q_{ti,j} \left| Q_{ti,j} \right|^m \quad (1)$$

where “j” is the index of the junctions that have pipelines connecting to junction “i”, L_j is the length of the pipe, A_j is the cross section area, $Q_{ti,j}$ is the total fluid flow rate in the pipe, m and K_j represents either Darcy-Weisbach or Hazen-Williams head loss coefficient of the pipe, and H_i and H_j denote head at “i” and “j” junctions, respectively. Here we assume that: (a) the total fluid flow satisfies the head loss equation; (b) flow and pressure vary slowly. The latter assumption enables us to neglect the head variation with time. This assumption can be eliminated in the future work to include the fast pressure variation during each time interval. Note that there is a nonlinear term at the right hand side of the equation (1). If we make the linearization for (1) and take finite difference for time derivative, we obtain

$$\frac{L_j}{g A_j} \frac{Q_{ti,j}^{n+1} - Q_{ti,j}^n}{\Delta t} = H_j^{n+1} - H_i^{n+1} - K_j Q_{ti,j}^{n+1} \left| Q_{ti,j}^n \right|^m \quad (2)$$

where n denotes the initial time step and $n+1$ denotes new time step to be calculated from the model. We take H_i and H_j at $n+1$ time step in (2) (whenever there is no indication of the time step for a property, it either means that the property is not time variation or it is calculated at n time step). Eq. (2) can be solved for Q^{n+1}

$$Q_{ti,j}^{n+1} = \frac{(H_j^{n+1} - H_i^{n+1})\Delta t + \frac{L_j}{g A_j} Q_{ti,j}^n}{\frac{L_j}{g A_j} + K_j \left| Q_{ti,j}^n \right|^m \Delta t} \quad (3)$$

At each junction, the continuity equation for each phase fluid reads

$$\sum_{j=1}^{N_i} Q_{\beta i,j}^{n+1} + E_{\beta i}^{n+1} = 0 \quad (4)$$

where $\beta = o$ and w , denoting oil and water phase, N_i denotes the number of surrounding junctions connecting to the junction “i”, and $E_{\beta i}$ denotes the phase exchange at junction “i”. The total flow continuity equation is then

$$\sum_{j=1}^{N_i} Q_{ti,j}^{n+1} + \sum_{\beta=o,w} E_{\beta i}^{n+1} = 0 \quad (5)$$

Substituting (3) into (5) to eliminate the flow rate at $(n+1)$ time, we have

$$\sum_{j=1}^{N_i} \frac{(H_j^{n+1} - H_i^{n+1})\Delta t + \frac{L_j}{g A_j} Q_{ti,j}^n}{\frac{L_j}{g A_j} + K_j \left| Q_{ti,j}^n \right|^m \Delta t} + \sum_{\beta=o,w} E_{\beta i}^{n+1} = 0 \quad (6)$$

Now, we need to propose an interaction model for Eoi and Ewi. Here, the expressions used in double porosity model are utilized, i.e.

$$E_{\beta i} = T_{m\beta i} (p_{m\beta i} - p_i) \quad (7)$$

and capillary equation

$$p_{mci} = p_{moi} - p_{mwi} \quad (8)$$

The head of fluid flow at each junction can be obtained by the following formulation

$$H_i = Z_i + \frac{p_i}{\gamma_i} \quad (9)$$

Upon substitution of (7) and (9) into (6), and then elimination of P_{mwi} from (8), the Eq. (6) can be written as

$$\sum_{j=1}^{N_i} \frac{(Z_j - Z_i + \frac{p_j^{n+1}}{\gamma_j} - \frac{p_i^{n+1}}{\gamma_i})\Delta t + \frac{L_j}{g A_j} Q_{ti,j}^n}{\frac{L_j}{g A_j} + K_j \left| Q_{ti,j}^n \right|^m \Delta t} - T_{moi}^n (p_{moi}^{n+1} - p_i^{n+1}) - T_{mwi}^n (p_{moi}^{n+1} - p_{mci}^n p_i^{n+1}) = 0 \quad (10)$$

In equation (10), we also used linearization for calculating matrix transmissivity, T_{moi} and T_{mwi} , and capillary pressure P_{mci} at n time step. There are two unknowns, junction pressure, P_i (and other junction pressure P_j), and matrix oil phase pressure, P_{moi} . For each junction in the network, we can write down one such equation. They form a large system of algebraic equations. To close the equation system, we employ fluid flow equations for matrix to proceed continuously.

$$\phi_i \frac{\partial S_{oi}}{\partial t} = -T_{moi} (p_{moi} - p_i) \quad (11)$$

$$\phi_i \frac{\partial S_{wi}}{\partial t} = -T_{mwi} (p_{mwi} - p_i) \quad (12)$$

$$S_{mwi} + S_{moi} = 1 \quad (13)$$

Combine equation (11) and (12), use condition (13) and (8), we have following equation associated with previous mentioned two unknowns

$$(T_{moi}^n + T_{mwi}^n) p_i^{n+1} - (T_{moi}^n + T_{mwi}^n) p_{moi}^{n+1} + T_{mwi}^n p_{mci}^n p_i^{n+1} = 0 \quad (14)$$

In the above equation, transmissibility is also linearized to n time step. Equation (10) and (14) constitute our new fractured reservoir simulation model. If there are J junctions in

our system, we can solve the equation system that consists of $2J$ equations with $2J$ unknowns, P_i and $P_{m_{oi}}$. After these two pressures are obtained, matrix saturations can be calculated from (11) and (12). Then, transmissibility and exchange fluid flow E_{oi} and E_{wi} can be updated. Substitute the solved head at $n+1$ time into (3), we are able to estimate total flow rate at new time step. Finally, through conservative equations (4) and (5), flow rate for each phase at new time step are obtained. These procedures can be repeated to calculate quantities at further time step.

Because the above model only needs to solve 2 unknowns simultaneously for all nodes and the governing equations are very simple, it is expected to be much faster than Continuum Double Porosity Model that requires solving an equation system with 4 unknowns. It will have significantly less computational work than that of Discrete Fracture Network model since this new model does not try to generate real fractures. By maintaining the concept of fast flow channels, i.e., pipelines, it is also more realistic than Continuum Single Porosity models that average fracture transmissibility with that of the matrix. This model can be extended to accommodate to any 3D geological structure without losing its simplicity. Boundary conditions constant pressures at the oil water contact and wellbore, plus well production rates.

3-D Fracture Modeling

In preparation for building a 3-D fracture model from our pipeline network solution algorithm, we sent two research associates on a 4-day training on the Dynamic Graphics software, EarthVision. This software will serve as a visualization tool for realization of direct and indirect fracture data using various fracture indicators.

Task V- Project Management

Principal investigators from Venoco and USC met during this quarter on a bi-weekly basis at the Venoco offices in Santa Barbara. Various components of tasks proposed under the statement of work were reviewed and prioritized. For each task, key research personnel were designated keeping in mind a team-work approach.

Dr. Ershaghi from USC took charge of supervising the design of the database and the reservoir modeling work. Karen Christensen from Venoco, took the responsibility of supervising the data acquisition and geological modeling tasks.

The following individuals were designated to assist with the proposed studies:

Database:

Ursula Wiley (USC), Kim Halbert (Venoco) and Tim Rathman (Venoco), Chris Knight (Venoco), I. Ershaghi (USC)

Reservoir Studies:

Ershaghi (USC), Lang Zhang (USC), Juan Angiano, Ursula Wiley

Geological Modeling

Mike Wracher (Venoco), Karen Christensen

Geophysical Modeling

Karen Christensen (Venoco)

Project Management:

Karen Christensen (Venoco) and I. Ershaghi (USC)

TASK VI-Tech Transfer

Budget Period I – Task VI includes a CD ROM and Web Page Tech Transfer of this database. The database has been designed and is currently being populated. A CD ROM will be written when this task has been completed. The preliminary work for the Intranet Site is underway. A structural skeleton of the database has been modified for the purposes of web use. Data population of this site is in progress.

Talks and Papers:

6/20/2000

Presented to AAPG/SPE regional convention

South Ellwood Field, Santa Barbara Channel: New Insight into Structures, Fractures, and Seeps. Karen Christensen, Mike Wracher, Gary Orr.

6/21/2000

Presented to AAPG/SPE regional convention

Reservoir Description in Three Dimensions. Mike Wracher

Conclusions

Three significant milestones were achieved during the first reporting period. A database structure was created to capture the regional and field specific information for South Ellwood. A first generation 3-D geologic model for the field was constructed in EarthVision. The main structural elements that control fracturing in the Monterey were defined. Finally a theoretical framework for a new reservoir simulation algorithm to model the complex fracture system was developed.

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